**TECHNICAL REVIEW DOCUMENT**
**For**
**RENEWAL of OPERATING PERMIT 96OPAD130**

Public Service Company – Cherokee Station
Adams County
Source ID 0010001

Prepared by Jacqueline Joyce
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Revised June 2009 and January 2010

## I. Purpose:

This document will establish the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewed Operating Permit proposed for this site. The original Operating Permit was issued February 1, 2002. The expiration date for the permit was February 1, 2007. However, since a timely and complete renewal application was submitted, under Colorado Regulation No. 3, Part C, Section IV.C all of the terms and conditions of the existing permit shall not expire until the renewal Operating Permit is issued and any previously extended permit shield continues in full force and operation. This document is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the renewal application submitted January 6, 2006, additional information received on December 3, 2009, comments on the draft permit and technical review document received on June 3, 2009, comments made from various individuals during the public comment period, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at http://www.cdphe.state.co.us/ap/Titlev.html. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this Operating Permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This Operating Permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this Operating Permit without applying for a revision to this permit or for an additional or revised construction permit.

## II. Description of Source

This facility is an electric generating facility. Electricity is produced through four coal-fired boilers. Although coal is the primary fuel burned, these units use natural gas as a back-up fuel. Unit 1 is a 115 MW boiler that is equipped with a baghouse to control particulate matter emissions, low $NO_X$ burners with over-fire air to control $NO_X$ emissions and a dry-sodium injection system to control $SO_2$ emissions. Unit 1 shares a stack with Unit 2. Unit 2 is a 114 MW boiler that is equipped with a baghouse, over-fire air and a dry sodium injection system. Unit 3 is a 168 MW boiler that is equipped with a baghouse, low $NO_X$ burners with over-fire air and a lime spray dryer system to control $SO_2$ emissions. Unit 4 is a 388 MW boiler that is equipped with a baghouse, low $NO_X$ burners with over-fire air and a lime spray dryer system. Other emission sources at Cherokee include fugitive emissions from coal handling and storage, ash handling and disposal and from traffic on paved and/or unpaved roads. Finally, Cherokee station has point source emissions from the five (5) ash silos, one (1) ash blower system, two (2) coal crushers, the coal conveying system, five (5) sodium reagent silos, four (4) cooling water towers and two (2) service water towers, two (2) emergency generators and one (1) aboveground gasoline storage tank. In order to support the lime spray dryer systems two (2) lime storage silos, two (2) ball mill slakers and two (2) recycle mixers were added to the facility and became operational in August 2002. In addition, Public Service Company (PSCo) entered into a Voluntary Emissions Reduction Agreement with the Division. The provisions of the agreement became effective on January 1, 2003 and the appropriate provisions of that agreement have been included in this permit.

The facility is located at 6198 Franklin Street in Adams County, within the Denver metro area. The Denver Metro Area is classified as attainment/maintenance for particulate matter less than 10 microns in diameter ($PM_{10}$) and carbon monoxide (CO). Under that classification, all SIP-approved requirements for $PM_{10}$ and CO will continue to apply in order to prevent backsliding under the provisions of Section 110(l) of the Federal Clean Air Act. The Denver metro area is classified as non-attainment for ozone and is part of the 8-hr Ozone Control Area as defined in Colorado Regulation No. 7, Section II.A.1.

There are no affected states within 50 miles of the plant. Rocky Mountain National Park and Eagles Nest National Wilderness Area, both Federal Class I designated areas, are within 100 kilometers of the plant.

The summary of emissions that was presented in the Technical Review Document (TRD) for the original permit issuance has been modified to more appropriately identify the **potential to emit (PTE)** of both criteria and hazardous air pollutants. Emissions (in tons/yr) at the facility are as follows:

| Emission Unit | PM | $PM_{10}$ | $SO_2$ | $NO_X$ | CO | VOC | Pb[1] | HAPS |
|---|---|---|---|---|---|---|---|---|
| Point Sources | | | | | | | | |
| Boiler 1 (Unit 1) | 609.7 | 560.92 | 6,706.66 | 3,658.18 | 502.10 | 32.88 | 0.11 | See Page 25 |
| Boiler 2 (Unit 2) | 609.7 | 560.92 | 6,706.66 | 4,877.57 | 502.10 | 32.88 | 0.11 | |
| Boiler 3 (Unit 3) | 822.13 | 756.36 | 9,043.39 | 3,781.78 | 677.04 | 44.33 | 0.15 | |
| Boiler 4 (Unit 4) | 1,541.76 | 1,418.42 | 16,959.36 | 6,167.04 | 362.77 | 83.13 | 0.29 | |
| Emergency Generator E001 | 0.26 | 0.26 | 1.31 | 8.3 | 2.2 | 0.21 | | |
| Emergency Generator E002 | 0.65 | 0.65 | 3.28 | 20.8 | 5.53 | 0.53 | | |
| Coal Handling (conveyors and crushers) | 47 | 23 | | | | | | |
| Ash Handling (grandfathered silos) | 9.25 | 9.25 | | | | | | |
| Ash Handling (permitted silos) | 19.2 | 19.2 | | | | | | |
| Unit 3 Ash Blower | 1.13 | 1.13 | | | | | | |
| Dry Sodium Reagent Silos | 0.03 | 0.03 | | | | | | |
| Lime Storage Silos | 0.0073 | 0.0073 | | | | | | |
| Ball Mill Slakers | 0.25 | 0.25 | | | | | | |
| Recycle Mixers | 0.25 | 0.25 | | | | | | |
| Cooling Water and Service Water Towers | 6.97 | 6.97 | | | | 6.54 | | |
| **Total Point Source Emissions** | **3,668.29** | **3,357.62** | **39,420.66** | **18,513.67** | **2,051.74** | **200.5** | **0.66** | **86.07** |
| | | | | | | | | |
| Fugitive Emission Sources | | | | | | | | |
| Coal Handling | 252.2 | 36.4 | | | | | | Negl. |
| Haul Road | 59.2 | 30.2 | | | | | | |
| **Total Fugitive Emissions** | **311.4** | **66.6** | | | | | | **Negl.** |
| | | | | | | | | |
| **Total Emissions** | **3,979.69** | **3,424.22** | **39,420.66** | **18,513.67** | **2,051.74** | **200.5** | **0.66** | **86.07** |

[1] Lead (Pb) emissions are based on emission factors from AP-42, Section 1.1 (dated 9/98), Table 1.1-17.

**Potential to emit** used in the above table are based on the following information:

**Criteria Pollutants**

Potential to emit for the Unit 3 ash blower, the two permitted ash silos, ball mill slakers, lime storage silos, recycle ash storage silos, recycle mixers and dry sodium reagent silos are based on permitted emissions.

Potential to emit for $NO_X$, $SO_2$ and PM from the boilers are based on emission limitations included in the permit (Reg 1 for $SO_2$ and PM (1.1 lb/mmBtu and 0.1 lb/mmBtu, respectively), Reg 1 $NO_X$ limits for Unit 1 (0.60 lbs/mmBtu) and Acid Rain $NO_X$ limits for the others (Unit 2 – 0.8 lb/mmBtu, Unit 3 – 0.46 lb/mmBtu and Unit 4 – 0.40 lb/mmBtu)), the design heat input rate and 8760 hours per year of operation. $PM_{10}$ emissions from the boilers are presumed to be 92% of PM emissions (per AP-42, Section 1.1 (dated 9/98), Table 1.1-6). VOC and CO emissions from the boilers are based on emissions from the worst case fuel. Emissions from VOC and CO were estimated using AP-42 emission factors (Section 1.1, dated 9/98, Tables 1.1-3 and 1.1-19 for coal and Section 1.4, dated 3/98, Tables 1.4-1 and 1.4-2 for natural gas) and the maximum fuel consumption rate. The maximum coal consumption rate is based on the design heat input rate, the heat content of the coal from the APEN submitted on April 30, 2008 and 8760 hours per year of operation. The maximum natural gas consumption rate is based on the design heat input rate, a natural gas heat content of 1020 Btu/scf (per AP-42) and 8760 hours per year of operation.

Potential to emit for the emergency generators is based on the following: for E001 permitted emissions ($NO_X$ and CO) and the permitted fuel consumption rate (a heat content of 130,000 Btu/gal was assumed) and AP-42 emission factors for other pollutants. For E002, potential to emit is based on the design heat input rate, AP-42 emission factors and 500 hours per year of operation. A fuel sulfur content of 0.5 weight percent was assumed in the emission calculations for both units E001 and E002.

Potential to emit from coal handling point source emissions (conveying and crushing) is based on the estimates provided in the original Title V permit application submitted on November 15, 1995. Note that no credit was taken for covers and/or enclosures with these estimates.

Potential to emit from the grandfathered ash silos is based on the maximum coal consumption rate for Units 1 and 3 and the emission factors and waste ash determination methodology specify in the current Title V permit. Note that the ash content of the coal was assumed to be 9.95% which was the value used to set permit limits for the Unit 2 and 4 waste ash silos.

Potential to emit from the cooling and service water towers is based on the equations included in the current Title V permit and the information provided in the original Title V permit application submitted on November 15, 1995.

Potential to emit from fugitive emissions from haul roads, coal handling and ash handling are based on the estimates provided in the original Title V permit application submitted on November 15, 1995.

**Hazardous Air Pollutants (HAP)**

The potential to emit table on page 3 provides total HAPs for each operating permit. The breakdown of HAP emissions by individual HAP and emission unit is provided on page 25 of this document. HAP emissions, as shown in the table on page 25, are based on the following information:

Potential to emit of HAPS were only determined for the boilers, the emergency generators and the cooling and service water towers. HAPS were not estimated for the other emission units as HAPs were presumed to be negligible from these sources.

HAP emissions from the emergency generators are based on AP-42 emission factors (Section 3.4, dated 10/96, Table 3.4-3) and the permitted fuel consumption rate (a heat content of 130,000 Btu/gal was assumed) for E001 and the design heat input rate and 500 hours per year of operation for E002.

Metal HAP emissions from the boilers are based on AP-42 emission factors (Section 1.1, dated 9/98, Table 1.1-18) and the maximum coal consumption rate. Mercury emissions from the boilers are based on performance tests conducted in October and December 2008 for Units 1 through 3 and the average projected mercury emissions that were used in the development of Colorado's Mercury Rule for Unit 4. HF and HCl emissions from the boilers are based on the maximum emission factor, in units of lbs/ton, determined from reported HF and HCl emissions and coal consumption on several current APENS (2007, 2006, 2005 and 2004 data) and the maximum coal consumption rate. Note that these emissions take credit for the control devices on the boilers. Emissions of benzene, formaldehyde and toluene are based on AP-42 emission factors (Section 1.4, dated 3/98, Table 1.4-3) and the maximum natural gas consumption rate. Emissions of hexane are based on an EPRI emission factor (from an EPRI paper, dated May 2000) and the maximum natural gas consumption rate.

HAP emissions from the cooling towers are based on the design circulation rate, 8760 hours per year of operation and the chloroform emission factor specified in the Title V permit (based on a letter from Wayne C. Micheletti to Ed Lasnik, dated November 11, 1992).

Note that actual emissions are typically less than potential emissions and actual emissions from the PSCo sources are shown on page 26 of this document.

Compliance Assurance Monitoring (CAM) Requirements

The source addressed the applicability of the CAM requirements in their renewal application and is discussed further in the document under Section III – Discussion of Modifications Made, under “Source Requested Modifications”.

MACT Requirements

Case-by-Case MACT - 112(j) (40 CFR Part 63 Subpart B §§ 63.50 thru 63.56)

Under the federal Clean Air Act (the Act), EPA is charged with promulgating maximum achievable control technology (MACT) standards for major sources of hazardous air pollutants (HAPs) in various source categories by certain dates. Section 112(j) of the Act requires that permitting authorities develop a case-by-case MACT for any major sources of HAPs in source categories for which EPA failed to promulgate a MACT standard by May 15, 2002. These provisions are commonly referred to as the “MACT hammer”.

Owners or operators that could reasonably determine that they are a major source of HAPs which includes one or more stationary sources included in the source category or subcategory for which the EPA failed to promulgate a MACT standard by the section 112(j) deadline were required to submit a Part 1 application to revise the operating permit by May 15, 2002. The source submitted a notification indicating that Cherokee Station was a major source for HAPS, with equipment under the source category for reciprocating internal combustion engines.

Since the EPA has signed off on final rules for all of the source categories which were not promulgated by the deadline, the case-by-case MACT provisions in 112(j) no longer apply. Note that there is a possible exception to this, as discussed later in this document (see under industrial, commercial and institutional boiler and process heaters).

RICE MACT (40 CFR Part 63 Subpart ZZZZ)

The RICE MACT (40 CFR Part 63 Subpart ZZZZ) was signed as final on February 26, 2004 and was published in the Federal Register on June 15, 2004. An affected source under the RICE MACT is any existing, new or reconstructed stationary RICE with a site-rating of more than 500 hp and located at a major source for HAPS; however, only existing (commenced construction or reconstruction prior to December 19, 2002) 4-stroke rich burn (4SRB) engines with a site-rating of more than 500 hp were subject to requirements. There are two diesel fired emergency generators included in Section II of the permit that are greater than 500 hp. Since the emergency generators are existing compression ignition engines, they do not have to meet the requirements of Subparts A and ZZZZ, including the initial notification requirements as specified in 40 CFR Part 63 Subpart ZZZZ § 63.6590(b)(3).

In addition, revisions were made to the RICE MACT to address engines $\leq$ 500 hp at major sources and all size engines at area sources. These revisions were published in the Federal Register on January 18, 2008. Under these revisions, existing compression ignition (CI) engines, 2-stroke lean burn (2SLB) and 4-stroke lean burn (4SLB) engines are not subject to any requirements in either Subparts A or ZZZZ (40 CFR Part 63 Subpart ZZZZ § 63.6590(b)(3)). For purposes of the MACT, for engines $\leq$ 500 hp, located at a major source, existing means commenced construction or reconstruction before June 12, 2006. There are two engines listed in the insignificant activity list that are less than 500 hp, a emergency fire pump (412 hp) and a lime slurry pump (140 hp). These engines were installed prior to June 12, 2006; therefore, these engines are not subject to the MACT.

Industrial, Commercial and Institutional Boilers and Process Heaters MACT (40 CFR Part 63 Subpart DDDDD)

The final rule for industrial, commercial and institutional boilers and process heaters was signed on February 26, 2004 and was published in the Federal Register on September 13, 2004. There are propane portable heaters included in the insignificant activity list in Appendix A of the permit. However, these units do not meet the definition of boiler or process heater specified in the rule (the definition of process heater excludes units used for comfort or space heat). Therefore the heaters included in the insignificant activity list would not be subject to the Boiler MACT requirements.

As of July 30, 2007, the Boiler MACT was vacated; therefore, the provisions in 40 CFR Part 63 Subpart DDDDD are no longer in effect and enforceable. The vacatur of the Boiler MACT triggers the case-by-case MACT requirements in 112(j), referred to as the MACT hammer, since EPA failed to promulgate requirements for the industrial, commercial and institutional boilers and process heaters by the deadline. Under the 112(j) requirements (codified in 40 CFR Part 63 Subpart B §§ 63.50 through 63.56) sources are required to submit a 112(j) application by the specified deadline. As of this date, EPA has not set a deadline for submittal of 112(j) applications to address the vacatur of the Boiler MACT. It is not clear whether 112(j) applications would be required for emission units, such as the small heaters used for comfort heat, which were excluded from the Boiler MACT. Therefore, the Division has not included a requirement in the permit to submit a 112(j) application. If the Division considers that in the future, a 112(j) application will be required for these small units the source will be notified.

Gasoline Distribution MACTs

A 1,000 gallon aboveground gasoline tank is included in Section II of the permit. There are potential MACT standards that could apply to this operation: Gasoline Distribution (Stage I) – 40 CFR Part 63 Subpart R (final rule published in the federal register on December 14, 1994), Gasoline Dispensing Facilities – 40 CFR Part 63 Subpart CCCCCC (final rule published in the federal register on January 10, 2008) and Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities – 40 CFR Part 63 Subpart BBBBBB (final rule published in the Federal Register on January 10, 2008).

Both of the rules published on January 10, 2008 only apply at area sources. Since this facility is a major source for HAPS, the requirements in those rules do not apply to the gasoline tank at this facility. The Gasoline Distribution (Stage I) MACT applies to bulk gasoline terminals and pipeline break-out stations. The gasoline dispensing equipment at this facility does not meet the definition of a bulk gasoline terminal or a pipeline break-out station. Therefore, none of the MACT requirements associated with gasoline distribution apply to the equipment at this facility.

Federal Clean Air Mercury Rule Requirements

The EPA published final rules to address mercury emissions from coal-fired electric steam generating units on March 15, 2005. These rules are referred to as the Clean Air Mercury Rule (CAMR), which required mercury standards for new and modified emission units and provided a trading program for existing units. Under this program, sources would be required to get a permit (application due date July 10, 2008) and to meet monitoring system requirements (install and conduct certification testing) by January 1, 2009.

However, on February 8, 2008 a DC Circuit Court vacated the CAMR regulations for both new and existing units. Therefore, the federal CAMR requirements are not in effect, as of the issuance of this renewal permit.

State Clean Air Mercury Rule Requirements

Although the Division did adopt provisions from the federal CAMR rule into our Colorado Regulation No. 6, Part A, the Division also adopted State-only mercury requirements in Colorado Regulation No. 6, Part B, Section VIII. As discussed above the provisions from the federal CAMR rule have been vacated and are no longer applicable. While the state-only mercury requirements rely in some part of the federal CAMR rule (primarily for monitoring and reporting requirements), there are emission limitations and permit requirements that do not rely on the federal rule and are still in effect. In addition, on November 20, 2008, the Colorado Air Quality Control Commissions (AQCC) adopted into Reg 6, Part B, Section VIII, the monitoring, recordkeeping and reporting requirements in the vacated CAMR rule. The revisions to Reg 6, Part B take effect on December 30, 2008.

To that end, as existing mercury budget units the boilers are required to comply with either of the following standards on a 12-month rolling average basis beginning January 1, 2014 (Colorado Regulation No. 6, Part B, Section VIII.C.1.b):

0.0174 lb/GWh OR 80 percent capture of inlet mercury

The boilers would be subject to more stringent mercury standards beginning January 1, 2018 as set forth in Colorado Regulation No. 6, Part B, Section VIII.C.1.c.

It should be noted that if any of the boilers qualify as a low emitter (actual mercury emissions of no more than 29 lbs/yr), the mercury standards indicated above do not apply.

Since the mercury limitations do not apply until 2014 and the permit application is not due until 18 months prior to commencing construction on the mercury control equipment (Colorado Regulation No. 6, Part B, Section VIII.D.2) the renewal permit does not include the state-only mercury requirements.

Regional Haze Requirements

Unit 4 at this facility is subject to the regional haze requirements for best available retrofit technology (BART) and as such a BART analysis was conducted and a permit has been issued to address the BART requirements. The BART requirements have been included in Colorado Construction Permit 07AD0108B, which was issued September 12, 2008.

Although emission limitations for PM, $SO_2$ (annual limitations) and $NO_X$ are included in the BART permit, only the PM and $NO_X$ emission limitations are new. The $SO_2$ limitations that were included in the BART permit are the same limitations included in the current Title V permit, which were based on the Voluntary Emissions Reduction Agreement.

The BART permit specifies that PSCo shall demonstrate compliance with the PM and $NO_X$ unit-specific emission limits as expeditiously as practicable, but in no event later than five years following EPA approval of the state implementation plan for regional haze that incorporates these BART requirements, whichever is earlier. Although the PM and $NO_X$ requirements in the BART permit do not take effect until EPA approves the Regional Haze SIP and the BART permit does not require that a Title V permit application to incorporate the BART provisions be submitted until 12 months after startup of the modified $NO_X$ control equipment, the provisions in the BART permit have been included in the renewal permit.

Note that even though only Unit 4 is BART-eligible, the BART permit (07AD0108B) includes $NO_X$ and PM emission limitations for Unit 2. The Metro Units (Valmont, Cherokee and Arapahoe) were part of a BART alternative and as such additional $NO_X$ and PM emission limitations were taken for Unit 2.

## III. Discussion of Modifications Made

**Source Requested Modifications**

### January 6, 2006 Renewal Application

The source requested the following changes in their January 6, 2006 renewal application.

Section I, Condition 5 (Compliance Assurance Monitoring (CAM))

The source indicated that this condition needed to be revised to address the CAM requirements for this facility.  The CAM requirements apply to any emission unit that uses a control device to meet an emission limitation or standard and has pre-controlled emissions above the major source level.  There are several emission points at the facility that could potentially be subject to the CAM requirements.  The source provided information regarding the applicability of the CAM requirements to the emission units at the facility as discussed below.

**Emission sources with no emission limitations**

The source identified the following activities as units with no emission limitations and therefore not subject to the CAM requirements:  fugitive emissions from coal handling and storage, ash handling and disposal and traffic on paved and unpaved roads, the gasoline storage tank, the grandfathered ash storage silos, emergency generator E002, coal handling point source emissions (conveyors and crushers) and the cooling and service water towers.

**Emission sources with emission limitations**

**No control device**

Emergency generator E001 is subject to emission limitations; however, the unit is not equipped with a control device.

Although not specifically identified as an uncontrolled emission unit in the source's renewal application, the Division considers that the Unit 3 ash blower vent is uncontrolled.  As indicated in the technical review document for the original Title V permit (issued ), air from the blower is filtered before being exhausted.  Since the blower cannot be operated without the filter system, the filter system is not considered a control device, because it is integral to the operation of the unit.  Since the ash blower is not equipped with a control device, it is not subject to CAM.

**Pre-control emissions below the major source level**

The following emission units have pre-control emissions below the major source level and therefore are not subject to CAM.

Dry sodium reagent silos and lime silos:  PM and $PM_{10}$ emissions were calculated for these emissions units using the uncontrolled emission factors specified in the permit and the permitted throughput rate and uncontrolled emissions were below the major source level.

Recycle ash mixers and ball mill slakers: Permitted emissions from these emission units are based on grain loading specifications from the manufacturer and design rate for the blowers. Therefore estimating uncontrolled emissions are difficult. Based on the permitted emission rate, the associated control devices would have to have a control efficiency of greater than 99.7% in order to have uncontrolled emissions below the significance level. For the mixers and slakers, the Division has considered that for similar emission units that the control efficiency is about 95%. Therefore, the Division considers that uncontrolled emissions from these units are below the major source level.

Unit 2 and Unit 4 waste ash silos: There are essentially two activities performed at the waste ash silos, loading and unloading. Both activities use different emission factors and different control methods and for that reason the source considers that each activity should be considered separately. Emissions from silo loading are controlled by a baghouse. When ash is unloaded from the baghouse, the ash is blended with water in a pug mill located at the base of a silo and then released down a chute to an open truck.

For the Unit 2 waste ash silos, using the uncontrolled emission factors and permitted processing rate, uncontrolled emissions from both loading and unloading operations combined are below the major source level.

For the Unit 4 waste ash silo, using the uncontrolled emission factors and permitted processing rate, uncontrolled emissions from loading operations are below the major source level and therefore not subject to CAM but uncontrolled emissions from unloading operations are above the major source level.

The source considers that the loading process is controlled and the unloading process is uncontrolled. In the renewal application, the source indicates that they believe that mixing the ash with water is inherent to the process, because mixing water with the ash is necessary to make it possible to handle during the unloading, transport and disposal of the ash. While the Division is not necessarily convinced that the unloading process (mixing ash with water) is inherent process equipment, we do not think that it meets the definition of control equipment. The preamble to the CAM rule provides more insight into the control technology definition and provides the following (from October 22, 1997 Federal Register, page 54912, 3rd column, under *control devices criterion*)

> The final rule provides a definition of "control device" that reflects the focus of Part 64 on those types of control devices that are usually considered as "add-on" controls." This definition does not encompass all conceivable control approaches but rather those types of control devices that may be prone to upset and malfunction, and that are most likely to benefit from monitoring of critical parameters to assure that they continue to function properly. In addition, a regulatory obligation to monitor control devices is appropriate because these devices generally are not a part of the source's process and may not be

watched as closely as devices that have a direct bearing on the efficiency or productivity of the source.

The Division considers that for the unloading process the operation of the pug mill to mix the ash with water is not considered an add-on control device and is not the type of device that would benefit from monitoring critical parameters. Therefore, the Division agrees that based on the specific provisions in the CAM requirements that unloading ash from the silo is an uncontrolled activity. Therefore, the Division considers that the CAM requirements do not apply to the ash silo unloading operations.

**Pre-control emissions above the major source level**

The source identified the boilers as being subject to CAM, since control devices are required to meet the PM emission limitations. All the boilers are subject to PM, $SO_2$ and $NO_X$ emission limitations. Controlled emissions of these pollutants exceed the major source level and these units use emission controls (baghouses for PM, lime spray dryer or dry sodium injection for $SO_2$ and low $NO_X$ burners and/or over-fire air for $NO_X$ (Unit 2 only has over-fire air)) to meet its emission limitations. Therefore, the boilers are potentially subject to the CAM requirements.

The boilers subject to $SO_2$ and $NO_X$ emission limitations under the Acid Rain Program, the requirements of which are included in Section III of the current permit. Pursuant to 40 CFR Part 64 § 64.2(b)(1)(iii), the CAM requirements do not apply to Acid Rain Program emission limitations.

The boilers are subject to a short-term $SO_2$ emission limitation (3-hr rolling average) and an annual $SO_2$ emission limitation for the Metro units (per a voluntary emissions reduction agreement) and Units 1 and 4 are subject to 30-day $SO_2$ emission limits (only applies during part of the year) and a 20% reduction requirement (on a calendar year basis). The current Title V permit requires that the source use continuous emission monitoring systems to demonstrate compliance with the $SO_2$ emission limitations. Therefore, since the Title V permit specifies a continuous compliance method for these emission limitations, the CAM requirements do not apply in accordance with the provisions in 40 CFR Part 64 § 64.2(b)(1)(iv).

Boilers 1, 3 and 4 are subject to 30-day $NO_X$ limitations and the current Title V permit requires that the source use continuous emission monitoring systems to demonstrate compliance with the $NO_X$ emission limitations. Therefore, as discussed above for $SO_2$, since the permit specified a continuous compliance method for these emission limitations, the CAM requirements do not apply.

CAM does apply to the boilers with respect to the PM emission limitations. Note that although the boilers are subject to opacity limits, they are not emission limitations subject to CAM requirements. The source submitted a CAM plan with their renewal application. In their CAM plan, the source proposed visible emissions, pressure differential and preventative maintenance as indicators. For visible emissions, excursions are identified as an opacity value exceeding 15% for one minute or more and any long term increase in opacity of 10% above baseline levels for normal operation. For pressure differential, an excursion is defined as an increase in differential pressure of 3 inches of water column or greater from normal baseline levels accompanied by a sustained increase in opacity over 10%.

The Division has reviewed the CAM plan submitted and while we accept the plan in part, we consider that changes to the plan are necessary. The Division considers that the following changes are necessary to the plan.

Visible Emissions

The Division agrees that sudden spikes in opacity are a reasonable indicator that the baghouse operation may have been compromised. The 15% indicator level proposed by PSCo is below the opacity limitations set for each unit. Although PSCo has not correlated 15% to a level of PM emissions, this is a short term (one minute or more) indicator of baghouse performance and as specified in 40 CFR Part 64 § 64.4(c)(1), emission testing is not required to be conducted over the indicator range or range of potential emissions. Given that the PM standard is based on the average of three one (1) hour tests and past performance tests indicate that the PM emissions are less than 50% of the standard, the short term 15% opacity indicator serves to provide an indication of proper baghouse operation and as such can be reasonable indicator that Units 1 through 4 are in compliance with the PM limitations.

The second indicator range of “a long term increase in opacity emissions from baseline conditions during normal operations to opacity emissions greater than 10% over an extended period of time” proposed by the source is non-specific as to the time frame (i.e., averaging time) and it is not clear that the 10% opacity represents an acceptable opacity level as an indicator range. Specifically PSCo did not correlate the 10% opacity to a PM emission level, nor did they submit any performance test data with their CAM plan.

Therefore, the Division will include as CAM, the compliance provisions required for new (constructed after February 28, 2005) electric utility steam generating units subject to PM fuel based emission limitations (i.e. units of lb/mmBtu) in 40 CFR Part 60 Subpart Da, since such monitoring represents presumptively acceptable monitoring in accordance with the provisions in 40 CFR Part 64 § 64.4(b)(1)(4). The compliance provisions specified in Subpart Da require that a baseline opacity level be set during a performance test and then requires monitoring of opacity emissions on a 24-hour average. If the opacity 24-hour average exceeds the baseline level, then the source must investigate and take the appropriate corrective action.

The baseline opacity level determined under the provisions of NSPS Subpart Da specify that 2.5% opacity be added to the average opacity determined during the performance test, although the baseline opacity level can be no lower than 5% opacity. Since the units required to conduct this monitoring under NSPS Subpart Da are subject to more stringent particulate matter limitations, the opacity add-on level will be higher (ranging from 2.5% to 5%) and will be based on the results of the performance test. However, in no case would the baseline opacity be set lower than 5%.

The Division intends to require that performance tests be conducted within 180 days of renewal permit issuance to demonstrate compliance with the PM emission limitation, therefore, the permit will require that PSCo set the baseline opacity during these tests. Although a performance tests were conducted on these units in 2003 and information on opacity emissions during the tests may be available (PSCo is only required to retain monitoring data for five years after it is generated) and thus may be used to set the indicator range, the Division considers that it is more appropriate to set the indicator range on a more recent test. As indicated in 40 CFR Part 64 § 64.4(e)(2), if installation of equipment and/or performance testing to set indicator ranges is necessary prior to performing the monitoring under CAM, then the schedule for completing installation and/or testing and beginning operation of the monitoring shall be as expeditiously as practicable but no longer than 180 days after approval of the permit. To that end, the permit requires that the performance tests be conducted, the proposed baseline opacities be submitted for Division approval and that monitoring of the 24-hour opacity averages commence within 180 days of renewal permit issuance. In addition, the permit will require the source to submit a minor modification application to revise the Title V permit and incorporate the proposed baseline opacities as the indicator ranges for the 24-hr average opacities. Such application shall be submitted with the proposed baseline opacities.

Pressure Differential

The source has indicated that an excursion would be “an increase in differential pressure across a baghouse of 3 inches of water column or greater from the unit’s normal specific operating load during normal operating conditions, as well as a sustained increase in opacity greater than 10%”. While the proposed language does not specifically define the pressure differential for the “unit’s normal specific operating load”, in their justification the source indicates that the normal pressure differential varies based on the operating load. While the Division understands that it may be difficult to identify specific ranges since the appropriate pressure differential varies depending on the load, failure to identify the specific range makes it difficult for the Division to independently determine whether an excursion has occurred. In addition, as indicated in the CAM plan, an increase or decrease in the pressure differential from the normal level at a specific operating load is not necessarily considered an indicator of decreased baghouse performance by itself. However, an increase or decrease in the pressure differential from the normal level, accompanied by a sustained increase in opacity is an indication of potential baghouse problems.

Since the normal pressure differential is specific to load and cannot be easily defined and because pressure differential by itself is not necessarily an indicator of potential problems with the baghouse, the Division will not include pressure differential in the CAM plan as an indicator. In accordance with 40 CFR Part 64 § 64.4(b)(4), presumptive CAM is monitoring included for standards that are exempt from CAM (i.e. NSPS standards promulgated after November 15, 1990) to the extent that such monitoring is applicable to the performance of the control device (and associated capture system). As discussed previously, the Division has revised the source's CAM plan to require that visible emissions be monitored in accordance with the monitoring required for new boilers subject to 40 CFR Part 60 Subpart Da. The emission limitations and monitoring for new boilers were published as final in the February 27, 2006 federal register, although changes to the monitoring requirements were published as final in the federal register on June 13, 2007. New boilers subject to the revised PM emissions limits in 40 CFR Part 60 Subpart Da are required to monitor compliance with the PM emission limitation using their COM by establishing a baseline opacity. Therefore, the baseline opacity monitoring that the Division is including in the CAM plan represents presumptive CAM and the Division does not believe that it is necessary to include pressure differential as an additional indicator.

It should be noted that new sources subject to the NSPS Da PM limitation are also required to conduct annual performance tests. While the Division has not included annual performance testing in the permit as part of the CAM plan, the Division does require performance tests as periodic monitoring to demonstrate compliance with the PM limitations. Frequency of testing is annual, unless the results of the testing are much lower than the standard, then less frequent testing is allowed.

Preventative Maintenance

The preventative maintenance that the source has proposed is a monthly review of historic minute opacity data and that based on this review, if warranted, repairs will be initiated to internal and/or external baghouse components. It is not clear what specifically the source would be looking for in the historic minute opacity data and what would trigger any repairs. The Division considers that preventative maintenance is important to the proper operation of the baghouse, therefore, the Division has revised the preventative maintenance indicator to require semi-annual internal inspections of the baghouse. This indicator has been included in other CAM plans for other PSCo facilities.

In general, the CAM plan has been included in Appendix H of the permit as submitted, except that the corrections indicated above have been made to the plan and some language has been omitted, revised or relocated in order to streamline the plan.

The boilers burn coal as their primary fuel; however, the boilers can operate on natural gas only as a back-up fuel. Although the boilers are equipped with baghouses, when burning natural gas, the boilers would be able to meet the PM emission limitations without the baghouses. Therefore, when the boilers burn only natural gas as fuel, CAM would not apply.

<u>Section II, Condition 4.4</u>

This permit condition requires that the No. 2 diesel fuel be sampled and analyzed semi-annually to determine the heat content of the fuel. It also allows, that if after the first two years following initial permit issuance, that if the heat content has not varied by more than 5%, that the average value shall be used in the emission calculations. The first two years of sampling have resulted in a variation of the heat content that is below 5%; therefore, the source has requested that this condition be revised to allow the average heat content to be used in the emission calculations.

The Division agrees that the average heat content can be used in the emission calculations. Therefore, Condition 4.4 has been removed and language has been added to Conditions 4.1.1 and 4.1.2 specifying the heat content of the diesel fuel to be used in the emission calculations.

<u>Section II, Condition 9.1</u>

The source requested that the operation and maintenance requirements for the boiler be linked to the CAM plan and suggest that the language in Condition 9.1 be revised to reference the CAM plan.

The Division has added the CAM requirements as “new” condition 1.5. The Division removed the language in Condition 9.1 regarding the COMS and opacity spikes. The Division considers that with the CAM plan requirements this language is no longer necessary.

<u>Section II, Condition 15.1.4</u>

The source indicated that the “startup period” of the voluntary agreement has passed and that this requirement should be removed from the permit. The change has been made as requested. In addition, the Division removed Condition 15.2.4, which also relates to the “startup period”.

<u>Section II, Condition 16</u>

The source indicated that the emission unit numbers listed for the recycle mixers, lime silos and ball mill slakers are not consistent with the emission unit numbers listed in the emission unit summary table in Section I, Condition 6.1. The Division has corrected the emission unit numbers in Section II, Condition 16 for the aforementioned equipment.

<u>Section III, Condition 2</u>

The source requested that the permit be revised to reflect the current Acid Rain $NO_X$ averaging plan for Units 1 and 2. A revised averaging plan was submitted on October 26, 2004. The revised averaging plan was only in effect for 2005 through 2006. However, revised $NO_X$ compliance plans were submitted on November 30, 2007, which included a revised averaging plan for Units 1 and 2. This plan was in effect for calendar years 2005 through 2009. The provisions in the November 30, 2007 $NO_X$ averaging plan were included in the draft permit that went to public comment in June 2009. The source submitted a revised $NO_X$ averaging plan on December 3, 2009, which covers calendar years 2010 through 2014. Since the proposed Title V renewal permit had not been submitted to EPA for their 45-day prior to receiving the revised averaging plan, the Division included the revised $NO_X$ averaging plan in the proposed renewal permit. The Division considers that the revised $NO_X$ averaging plan qualifies as an administrative amendment under the Acid Rain permit revisions requirements (40 CFR Part 72 Subpart H). The Acid Rain permit revision procedures indicate that the addition of a $NO_X$ averaging plan shall be processed under the typical or fast-track modification procedures (i.e. 30-day public comment and 45-day EPA review) per § 72.81(b)(3); however, they do not address revisions to an existing $NO_X$ averaging plan. Under the administrative permit revisions procedures in 40 CFR Part 72 § 72.83(a)(14), the incorporation of those changes that are similar to the changes in §§ 72.83 (a)(1) thru (13) may be processed as an administrative amendment. Changes in substitution or reduced utilization plans that do not result in a new unit may be processed as an administrative amendment per § 72.83(a)(7), while changes in a substitution or reduced utilization plan that results in a new unit must be processed under the standard permit modification procedures per § 72.81(b)(2). Therefore, since the Cherokee Acid Rain permit already includes a $NO_X$ averaging plan and since the revision to the $NO_X$ averaging plan does not result in the addition of any new unit to the plan, the Division considers that the revisions to the Acid Rain portion of the operating permit may be processed as an administrative amendment. Since administrative amendments are not subject to public comment, the Division considers that incorporating the revised $NO_X$ averaging plan into the proposed permit, after it has gone through public comment but before it has gone through EPA review, is acceptable.

**June 3, 2009 Comments on the Draft Permit and Technical Review Document**

The following changes were made in response to the comments submitted on June 3, 2009 on the draft permit and technical review document:

Section II, Condition 6.4

The ash throughput limit for the Unit 2 silo was corrected to 49,557 tons/yr. This is the throughput limit on which the emission limits are based.

Appendix A – Insignificant Activities

A portable diesel fired pump (80 hp) was added to the insignificant activity list.

**Other Modifications**

In addition to the modifications requested by the source, the Division has included changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this renewal.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments, to the Cherokee Station Operating Permit with the source's requested modifications. These changes are as follows:

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- Monitoring and compliance periods and report and certification due dates are shown as examples.  The appropriate monitoring and compliance periods and report and certification due dates will be filled in after permit issuance and will be based on permit issuance date.  Note that the source may request to keep the same monitoring and compliance periods and report and certification due dates as were provided in the original permit.  However, it should be noted that with this option, depending on the permit issuance date, the first monitoring period and compliance period may be short (i.e. less than 6 months and less than 1 year).

Section I - General Activities and Summary

- Revised Condition 1.1 to address the attainment status of the area in which the facility is located and to correct the Reg 7 citation for the definition of the 8-hour ozone control area (with recent revisions to Reg 7, this citation has changed).

- Removed the discussion regarding the startup of various control equipment in Condition 1.1, as the startup dates will be addressed in the Table in Section I, Condition 6.1.

- Made minor revisions to the language in Condition 3 (prevention of significant deterioration) to be more consistent with other permits.  In addition, revised this condition to address the attainment status of the area in which the facility is located.

- Added a column to the Table in Condition 6.1 for the startup date of the equipment.

Section II.1 – Boilers, Coal Firing

- Added unit numbers to the table header to more clearly identify the units.

- References to fuel usage or fuel sampling were replaced with coal usage or coal sampling.

- Revised the language in Condition 1.1.2 to specify that the performance tests shall be used to set the baseline opacity for the CAM plan and specified how the baseline opacity shall be determined.

- Removed the notation “effective January 1, 2005” from the Unit 1 $NO_X$ limit in Condition 1.6.2. Since January 1, 2005 has passed this note is not longer necessary.

- Revised the table column “Compliance Emission Factor” for Condition 1.11 by replacing “507 lbs/$10^{12}$ Btu” with “See Condition 1.11”.

Section II.2 –Boilers, Natural Gas Firing

- Added unit numbers to the table header to more clearly identify the units.

- Based on EPA’s response to a petition on another Title V operating permit, minor language changes were made to various permit conditions (both in the table and the text) to clarify that only natural gas is used as fuel for permit conditions that rely on fuel restriction for the compliance demonstration.

- Removed the notation “effective January 1, 2005” from the Unit 1 $NO_X$ limit in Condition 2.5.2. Since January 1, 2005 has passed this note is not longer necessary. In addition, the phrase “provided EPA approves the designation of the Denver area as a $PM_{10}$ attainment/maintenance area” was removed, since the Denver area has been designated as attainment/maintenance for $PM_{10}$.

Section II.3 – Boilers, Combination Fired

- Added unit numbers to the table header to more clearly identify the units.

Section II.4 – Emergency Generators

- Revised the opacity requirements (Condition 4.5) to require an annual Method 9 reading. Under the language in the current permit, if startup lasts less than 60 minutes and the generator runs less than 4 hours after startup, no opacity observation is required. The Division is requiring an annual opacity observation to be more consistent with the requirements in other Title V permits for emergency generators.

- Added language to the opacity requirements (Condition 4.5) to specify that copies of the Method 9 readings and the certified Method 9 reader’s certificate be maintained and made available to the Division upon request.

Section II.5 – Particulate Matter Emissions – Fugitive Sources

- Based on comments received during the public comment period, the following phrase was added to Condition 5.2 “[t]he 20% opacity, no off-property transport, and nuisance emission limitations are guidelines and not enforceable standards and no person shall be cited for violation thereof pursuant to C.R.S. 25-7-115.”

Section II.7 – Cooling and Service Water Towers

- Revised the equation for VOC emission calculations in Condition 7.1 to result in emissions in units of tons/yr rather than lbs/yr.

Section II.8 – Gasoline storage tank

- Added the following note under the table "Note that this emission unit is exempt from the APEN reporting requirements in Regulation No.3, Part A and the construction permit requirements in Regulation No. 3, Part B provided actual, uncontrolled emissions are less than the APEN de minimis level." This tank was previously categorically exempt from APEN reporting requirements. However, now that the Denver metro area has been designated non-attainment for ozone, the tank is no longer categorically exempt but is exempt if actual, uncontrolled emissions are below the de minimis level.

Section II.9 – Particulate Matter Emission Periodic Monitoring Requirements

- Revised the stack testing language in Condition 9.3 to clarify the frequency of testing. The language in the permit addresses testing within the expected five-year permit term. The permit terms may be extended, provided a timely and complete renewal application has been submitted. For the most part, complete and timely renewal applications have been submitted and the term of the permits have been extended beyond the originally anticipated five-year permit term. Therefore, the language has been revised to set specific deadlines for testing, which more appropriately reflects the Division's intent to require testing for particulate matter at a minimum of every five years. To that end, the language regarding waiving testing within the last two years of the permit term, in the event that annual testing was triggered, has been removed. In general, the results of the initial tests have not been above 75% of the standard and annual testing has not been triggered. Therefore, the Division considers that the language is not necessary.

Section II.10 – Continuous Emissions Monitoring System Requirements

- Removed the phrase "and the traceability protocols of Appendix H" from Condition 10.3.2, since Appendix H of the current version of 40 CFR Part 75 is "reserved". Note that Condition 10.3.1 specifies that the continuous emission monitoring systems are subject to the requirements of 40 CFR Part 75 and that would include any applicable appendices, regardless of whether or not they are specifically called out in this condition.

- Removed Condition 10.3.3.2 (data replacement requirements for acid rain emission limitations and annual $SO_2$ limitations). The Division's Field Service's Unit considers that data replacement requirements for annual emission limitations are not necessary; therefore, it has been removed. In addition, the Acid Rain Requirements (Section III of the permit) specify the use of data replacement requirements, so it is not necessary to include those requirements in this section of the permit.

- The Division had originally intended to remove Condition 10.4.3 (monitoring opacity when the COM is down) from the permit based on citizen comments on another Title V permit. Condition 10.4.3 was not included in the draft renewal permit that went through public comment. However, after further review and based on comments received during the public comment period for this facility, the Division has elected to retain this requirement in the permit.

  Although the coal-fired boilers are subject to continuous opacity monitoring requirements under 40 CFR Part 75, there are periods under Part 75 where monitor downtime is approved, such as period of calibration, quality assurance and monitor repairs, and the Division recognizes that even equipment that is well operated and maintained can experience periods of down time. The alternate opacity language is in addition to the Part 75 monitoring requirements and is intended to provide credible evidence of compliance with the opacity emissions limitations in the permit when the opacity monitor is down.

  The alternate opacity monitoring requirements specify three methods that the source may use to assess compliance with the opacity limits when the COMS are down for more than eight consecutive hours. These methods are back-up COMS, EPA Method 9 observations and an "opacity report during monitor unavailability". The back-up COMS and Method 9 observations are straight-forward and are based on the reference method testing. The "opacity report during monitor unavailability" is based on parametric monitoring. The language included in the permit requires that for the "opacity report during monitor unavailability" the permittee record the opacity monitoring reading before and after those periods that the COMS is unavailable. They must also record and maintain a description of operating characteristics that demonstrate the likelihood of compliance including, but not limited to, information related to the operation of the control equipment and any other operating parameters that may affect opacity. Past reports of this nature submitted for this facility have noted such items as whether there were operational problems with or corrective maintenance conducted on the baghouse, whether the pressure differential was in the normal range, the unit operating load, and whether there were unit upsets. As previously stated, the "opacity report during monitor unavailability" is intended to provide credible evidence, regarding compliance with the opacity limitations.

  In the February 24, 1997 Federal Register, EPA promulgated credible evidence revisions to 40 CFR Parts 51, 52, 60 and 61. EPA states the following in the preamble to this final rule (page 8314, 3rd column):

  > The credible evidence revisions are based on EPA's long-standing authority under the Act, and on amplified authority provided by the 1990 CAA Amendments. Section 113(a) of the Act authorizes EPA to bring an administrative, civil or criminal enforcement action "on

> the basis of any information available to the Administrator." In this provision, which predates the 1990 CAA Amendments, Congress gave EPA clear statutory authority to use any available information--not just data from reference tests or other federally promulgated or approved compliance methods--to prove CAA violations.

In addition, EPA stated that (page 8318, 1st column):

> To the contrary, with regard to sources subject to Title V permits, EPA generally expects that most if not all of the data that EPA would consider as potentially credible evidence of an emission violation at a unit subject to monitoring under the agency's proposed CAM rule would be generated through means of appropriate, well-designed parametric or emission monitoring submitted by the source itself and approved by the permitting authority, or through other requirements in the source's permit. Sources not subject to CAM should still be readily able to discern the information, for example information about the operation of pollution control devices, that is relevant to their compliance with applicable regulation.

Finally it should be noted that the alternative opacity monitoring language that is being put back into the Title V renewal permit is in the current Title V permit for this facility and has been in the permit since its' February 1, 2002 initial issuance. The initial Title V permit went through a 30-day public comment period and a 45-day EPA review period prior to issuance.

- Corrected the references to "Section V, Conditions 21.a and 21.b" in Condition 10.4.4 to "Section V, conditions 22.a and 22.b".

- Replaced the phrase "concerning upset conditions and breakdowns" with "concerning affirmative defense provisions for excess emissions during malfunctions" in Condition 10.5.5 to reflect revisions made to the Division's Common Provisions Regulation.

<u>Section II.15 – Voluntary Emissions Reduction Agreement – State-only Requirements</u>

Note that the Voluntary Emissions Reduction Agreement is currently a state-only enforceable requirement. However, upon approval of this agreement into the Visibility SIP, these provisions will become both state and federally enforceable.

- Removed Condition 15.1.5 "Startup Problems" since this situation applies to the initial startup of the control technology, not to routine startups of the equipment.

- Revised Condition 15.1.7 to to remove "startup problems".

- Revised Condition 15.2.1.1 to remove the references to "Startup Problems".

- Based on comments received during the public comment period a statement was added to Condition 15 indicating that the requirements are state-only enforceable until EPA approvals the BART portion of the Regional Haze SIP.

<u>"New" Section II.17 - Regional Haze Requirements</u>

As discussed previously in this document, a construction permit (07AD0108B) was issued on September 12, 2008 to address the regional haze requirements for BART. The appropriate applicable requirements from this permit have been included in the permit as follows:

- Control technology requirements (condition 1). The Division will include the language in this condition regarding the installation, modification and/or replacement of the $NO_X$ controls. The $SO_2$ control is already in place and operational and no changes to that technology is required by this permit.

- CEMS requirements (condition 2). The CEMS requirements are already included in the Title V permit.

- $NO_X$ emission limitations (condition 3). This condition will be included in the permit.

- $SO_2$ emission limitations (condition 4). The $SO_2$ emission limitations are the already included in the Title V permit.

- PM emission limitations – Unit 4 only (condition 5). This condition will be included in the permit.

- Compliance schedule (condition 6). This condition will be included in the permit.

- Submittal of Title V permit application (condition 7). Since the conditions of the BART permit are being incorporated into the Title V permit at this time, this condition is no longer relevant and won't be included in the permit.

- O & M plan requirements (condition 8). The appropriate monitoring requirements will be included in the Title V permit; therefore, this requirement will not be included in the permit.

- Demonstrating compliance with permit conditions (condition 9). The Division considers that the Responsible Official certification submitted in conjunction with the first semi-annual monitoring and permit deviation report submitted after the compliance date for the BART requirements will serve as the compliance demonstration; therefore, this requirement will not be included in the permit.

- General terms and conditions (condition 10). This condition addresses the applicability of general terms and conditions in the construction permit. They are not relevant to the title V permit and will not be include in this permit.

- Reporting requirements (condition 11). This condition will be included in the permit.

Section III – Acid Rain Requirements

- Revised the table in Section 2 to include calendar years corresponding to the relevant permit term for the renewal.
- Revised the $NO_X$ limit in the table in Section 2 for Units 3 and 4. The source had elected to comply with the Phase I $NO_X$ requirements in 1997. Beginning January 1, 2008, the source was subject to the Phase II $NO_X$ requirements. Therefore, those limits have been included in the permit.
- Minor changes were made to the standard requirements (Section 3), based on changes made to 40 CFR Part 72 § 72.9.
- Removed the requirement in Section 4 to submit a copy of any revised certificate of representation to the Division. Submitting a copy of the certificate of representation to the permitting authority is not required under the regulations.

Section IV – Permit Shield

- In Section 3 (Streamlined Conditions) the following changes were made:
  - In the fifth line, $1^{st}$ column, corrected the reference to "Section V, Conditions 21.b and c" to "Section V, Conditions 22.b and c".
  - In the fifth line, $1^{st}$ column, corrected the reference to "Condition 10.4.4" to "Condition 10.4.3".
  - Removed the eighth line (requirement to replace data as it applies to the COMS from construction permits 86AD352-1 and –2), since Condition 10.4.3 (opacity monitoring when the COMS is down) was removed from the permit. As indicated previously, this condition was removed based on comments from a citizen on another Title V permit. It has been the Division's experience that "gap filling" measures are not necessary as COMS are very reliable and typically have little monitor downtime.
  - Removed the ninth line (requirement to replace data as it applies to the $SO_2$ CEMS from construction permits 86AD352-1 and –2), since Condition 10.3.3 (data replacement requirements for periods when $SO_2$ CEMS is down) was removed from the permit. As indicated previously, the Division's Field Services does not consider that data replacement requirements are necessary. Appropriate operation of the CEMS may be determined based on monitor downtime.

## PSCo Cherokee Total HAP Emissions

| | HCl | HF | Mercury | Metals | Formaldehyde | Hexane | Acetaldehyde | BTEX | Chloroform | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| Boiler 1 | 4.11 | 14.97 | 3.96E-03 | 3.74 | 0.45 | 2.57E-03 | | 3.29E-02 | | 23.30 |
| Boiler 2 | 4.11 | 14.97 | 3.81E-03 | 3.74 | 0.45 | 2.57E-03 | | 0.00E+01 | | 23.28 |
| Boiler 3 | 1.42 | 4.33 | 4.91E-03 | 5.04 | 0.60 | 3.47E-03 | | 4.43E-02 | | 11.45 |
| Boiler 4 | 2.67 | 8.12 | 1.42E-02 | 9.46 | 1.13 | 6.50E-03 | | 8.31E-02 | | 21.48 |
| Emergency Generator E001 | | | | | 2.05E-04 | | 6.55E-05 | 3.27E-03 | | 0.00 |
| Emergency Generator E002 | | | | | 5.13E-04 | | 1.64E-04 | 8.13E-03 | | 0.01 |
| Cooling Towers | | | | | | | | | 6.54 | 6.54 |
| | | | | | | | | | | |
| Total | 12.31 | 42.38 | 2.69E-02 | 21.97 | 2.64 | 1.51E-02 | 0.00 | 0.17 | 6.54 | 86.07 |

HAP emission factors for boilers are based on emissions from worst case fuel.
Hexane emission factors for boilers, when burning natural gas are from EPRI paper, dated May 2000
HCl and HF emissions from the boilers are based on emission factors used to report actual emissions on APENs and most likely take credit for controls.

**PSCo Cherokee Actual Emissions (tons/yr)**

| Unit | PM | $PM_{10}$ | $SO_2$ | $NO_X$ | CO | VOC | HAPS |
|---|---|---|---|---|---|---|---|
| Boiler 1 | 34.0 | 31.3 | 1,941.4 | 1,283.0 | 83.6 | 9.7 | 11.0 |
| Boiler 2 | 31.5 | 28.9 | 1,924.4 | 2,716.7 | 97.9 | 10.5 | 10.5 |
| Boiler 3 | 61.6 | 56.6 | 786.5 | 1,795.4 | 168.1 | 16.5 | 3.5 |
| Boiler 4 | 86.8 | 79.8 | 2,429.8 | 4,499.9 | 274.9 | 33.8 | 8.9 |
| Emergency Generator E001 | 0.05 | 0.05 | 0.05 | 0.3 | 0.1 | 0.05 | |
| Emergency Generator E002 | 0.05 | 0.05 | 0.05 | 0.3 | 0.1 | 0.05 | |
| Coal handling – fug | 21.7 | 5.8 | | | | | |
| Coal handling - point source (conveyors and crushers) | 2.6 | 0.8 | | | | | |
| Ash Handling (all silos, grandfathered and permitted) | 4 | 4 | | | | | |
| Haul Roads – fug | 20.7 | 4.4 | | | | | |
| Unit 3 ash blower | 1.04 | 1.04 | | | | | |
| Dry sodium reagent silos (5) | 0.05 | 0.05 | | | | | |
| Ball mill slakers (2) | 0.25 | 0.25 | | | | | |
| Lime storage silos (2) | 0.004 | 0.004 | | | | | |
| Recycle mixers (2) | 0.25 | 0.25 | | | | | |
| Cooling water (4) and service water (2) towers | 9 | 9 | | | | 6.6 | 0.1 |
| | | | | | | | |
| Total | 273.59 | 222.29 | 7,082.20 | 10,295.60 | 624.70 | 77.20 | 34.09 |
| Total – Fugitive | 42.40 | 10.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Total - Point source | 231.19 | 212.09 | 7,082.20 | 10,295.60 | 624.70 | 77.20 | 34.09 |

Actual emissions from boilers 1 - 4 are from APEN submitted 4/30/08 (2007 data)

Actual emissions from the emergency generators and the sodium reagent silos based on APEN submitted 4/9/07 (2006 data)

Actual emissions from fly ash handling based on APEN submitted 4/13/06 (2005 data). Note this includes both permitted and grandfathered silos.

Actual emissions from the cooling and service water towers based on APEN submitted 10/4/05 (2004 data)

Actual emissions from coal handling (both point and fug), haul roads, lime silos, lime slaker, recycle mixers, cooling and service water towers (criteria pollutants) and ash blower based on APEN submitted 4/19/05 (2004 data)

HAP emissions from the boilers are HCl, HF, selenium and formaldehyde

HAP emissions from the cooling and service water towers are chloroform